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PROJECT #10

INSPECTION OF SUBSEA PRODUCTION SYSTEMS

by

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1. Introduction

The tremendous demand for oil and gas in the United States has depleted our oil and gas reserves to an extent which has caused concern for many years. Efforts to maintain American independence from foreign oil suppliers, along with the rising costs of imported oil, have made possible the consideration for development of marginal or previously unprofitable oil and gas fields in the deeper waters of the outer continental shelf (OCS).

The current development of subsea production systems for exploitation of these deep water petroleum reserves poses new inspection problems for the U.S. Geological Survey (USGS). This report presents the results of a study funded by USGS to explore techniques for inspection of sea floor completion and production equipment. A technique requiring neither divers nor submersibles has been identified and its detailed application for the Exxon subsea production system (SPS) is presented in Appendix A to this report. The technique uses production tubing within the system and could substantially reduce inspection expense and danger to inspectors which would otherwise be encountered during first-hand inspections. This technique is explained in detail in Sections 4 and 5. Section 6 contains a review of OCS orders applicable to subsea systems with suggested general inspection procedures. Appendix B includes the test procedure suggested to USGS by Shell/Lockheed for their subsea well control system, along with recommendations by HDL.

2. Types of Subsea Systems

Various approaches are being taken to produce oil from deeper water using subsea systems. There are three basically different approaches to deep water production:

1. The completely submerged, remote controlled system: Production equipment specifically designed for operation in the deep water environment is manifolded on a submerged template mounted on the ocean floor. Maintenance is by pump down tools and manned or remote manipulators. The Exxon Subsea Production System (SPS) discussed in Appendix A is of this type.

2. The atmospheric wellhead: Subsea production equipment is located in a chamber maintained at atmospheric pressure. The chamber is accessible to workers from transfer capsules or submersibles. This approach allows the use of conventional completion equipment and maintenance of that equipment by personnel in a dry, one-atmosphere environment. The Shell/Lockheed system discussed in the Appendix B of this type.

3. The surface-platform/deep water wellhead system: Innovative designs for surface production platforms which are being developed for use in deep water present unique structural evaluation problems. These systems are outside the scope of this report.

All these systems are being designed for depth capability of 1000 ft. and beyond, but most are presently confined to 300 ft. or less for ease of experimental testing. Although all these systems present challenging problems for inspection, the Exxon SPS was chosen for detailed investigation because it provided a range of inspection problems representative of subsea production systems. Sufficient design data were available on this system to permit a thorough evaluation of these problems.

3. Inspection Techniques and Procedures

As part of ongoing OCS lease management program, USGS personnel are responsible for ensuring that all offshore exploratory and production operations are performed in a safe and pollution-preventing manner according to published OCS orders. This responsibility is carried out by both scheduled and unscheduled inspections of all offshore operating facilities. In some cases, these inspections can be made by visual observation or by reading instruments while prescribed test procedures are carried out. In other cases, the inspector must question the lessee concerning installation of critical equipment or testing without actually observing the item in question. For obvious reasons, it is preferable to make first-hand observations whenever possible. In subsea operations, this brings up the question of the techniques and procedures required to perform these inspections. One very direct technique would be to employ submersible vehicles having windows for viewing of underwater equipment by trained inspectors. However, this method will evidently be very costly, requiring not only the submersible, but also a specially equipped surface support/launching vessel. Estimates for employing submersible vehicles are as high as $18 million[1] for development of a complete system including ship, submersible, and special tools. The submersible cost alone would be in the area of $1 to $2 million each. Thus, complete independence from reliance on the producers comes dearly. not a valid argument

Several of the more sophisticated subsea production systems feature personnel transfer capsules. At the risk of increasing dependence on producers, these company-operated submersible enclosures could be used. Still another alternative is the possibility of leasing submersibles and support ships from commercial organizations as helicopter transport is currently obtained by USGS to discharge its present inspection responsibilities. This would tend to defray the high purchase cost and also minimize reliance on producers.

However, the safety of the inspectors performing the underwater inspection is of primary concern. Well known potential dangers generally related to life support, structural integrity, and surface communications exist when manned submersibles are used in such operations. Accidents and human error occurring while submerged can be vastly more serious than if they occurred in the normal environment. The use of manned submersibles would also require a regular inspection of the submersible and its ancillary equipment to assure safety. The added burden of such a program, if undertaken, is self-evident. unnecessary

[1] Unpublished correspondence, Dr. J. D. Stochiw, NUC to J. Meek, HDL. 23 Jan 1976.

Another alternative is the use of an unmanned submersible. The use of unmanned, remote controlled underwater vehicles with television and manipulators would eliminate personnel danger. However, extra costs and possible technical limitations make a third alternative desirable if feasible. This alternative is to provide remote read-out so that inspectors may perform the inspections from aboard the production-support vessels or deep-water platforms already in use by the lessees. The alternative would require that techniques be used to sense the item in question at the subsea wellhead or production equipment and transmit this critical information to the surface. This sensing may require installation of position, pressure, and thermal transducers in valves, pipes, pumps, etc., located in the subsea environment. Telemetering the information to the surface could involve ultrasonic, hydraulic, electric-wire, or other transmission techniques. The information displays could inlcude visual gages or meters, and computer controlled cathode-ray tubes (CRT's).

The considerations discussed above place inspection techniques and procedures in three categories; i.e., those performed by manned submersibles, by unmanned submersible, and by remote control/display. Ultimately, it would appear that emphasis should be placed on sensors on the subsea system, with data display or readout at the surface vessel or platform. Increased use of sensors, however, will require the development of methods for their calibration. A method for calibrating pressure transducers and determining existence and magnitude of leakage through closed valves is presented in the next secion of this report. This approach would eliminate the need for very costly submersible vehicles and the support ships required for them, as well as avoid a possible source of risk to USGS inspectors.

4. Calibration and Inspection Technique

Production or service tubing that is accessible at the surface can be used for calibration of pressure sensors and determining valve leakage if a tubing path to the component to be monitored can be isolated by remotely actuated valves. If a closed volume of fluid can be obtained in this way, net leakage into or out of the volume can be determined by a pressure rise or drop, respectively, which is measured at the surface. If leakage occurs, the magnitude of the leak can be determined by measuring the flow rate required to hold the surface pressure constant while bleeding fluid from or pumping fluid into the tubing (assuming the fluid in the tubing is in thermal equilibrium with the surroundings). If there is no leakage or if the leakage is very small, the process may be used to calibrate subsurface pressure transducers. Surface readings of pressure in the closed volume can be used to calibrate the remote read out of subsurface transducers monitoring the pressure in the volume if the surface readings are compensated for the hydraulic gradient in the enclosed fluid. This compensation and associated errors are discussed in the following section.

This technique for calibration and inspection of subsea transducers and valving requires only that the inspector have access to the pipelines that connect the subsea system to its surface production and distribution systems. Closed volumes are obtained in these pipelines by appropriately setting (turning on or off) various valves in the pipeline and subsea systems. Appendix A of this report applies this technique to the Exxon SPS and shows that the necessary closed volumes can be obtained for this system to permit inspection of all necessary points.

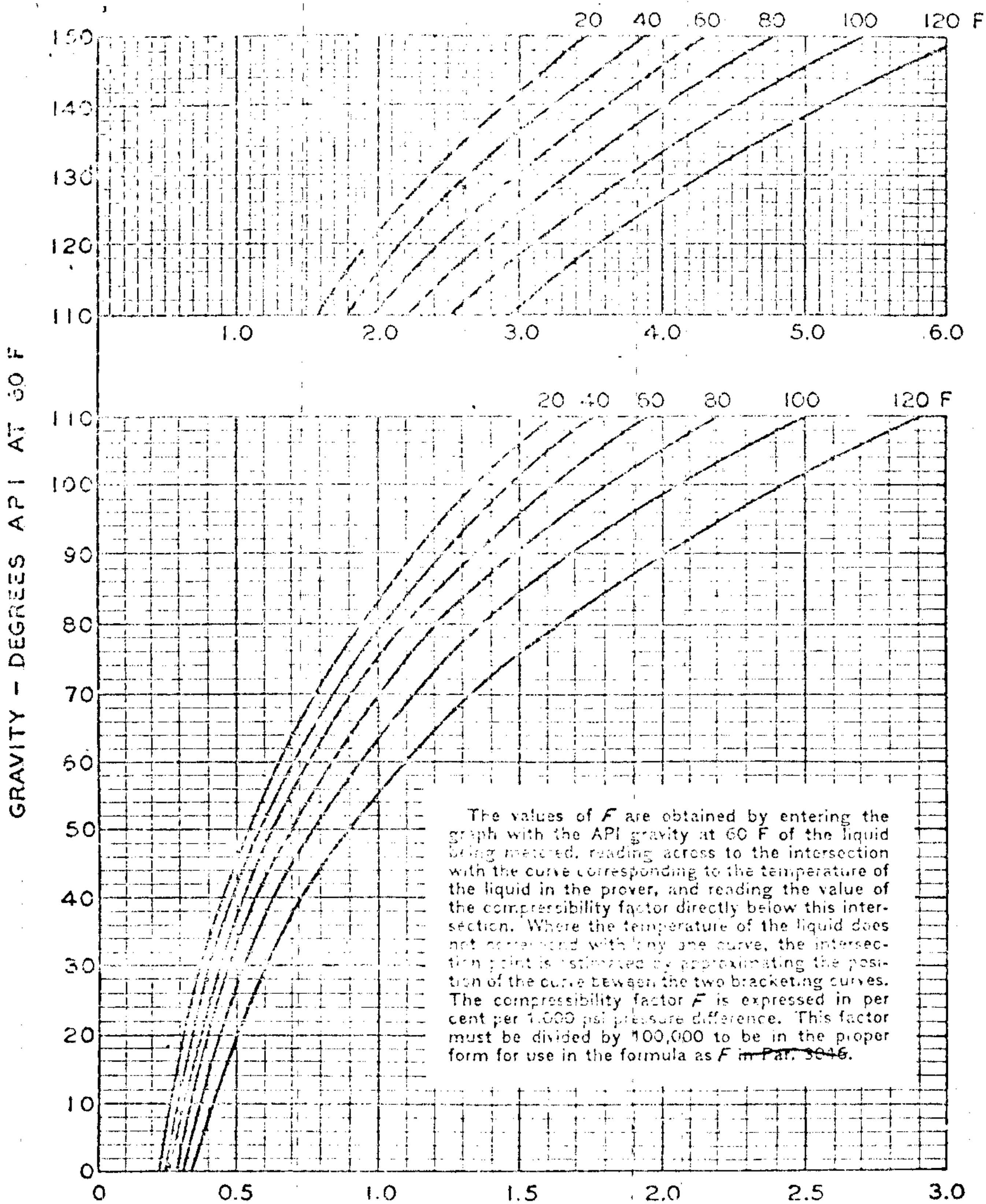
5. Pressure Transducer Calibration We do not nee. this section

If a pressure transducer at the bottom of a long column of fluid (liquid or gas) is to be calibrated by applying pressure at the top, then the pressure read at the top must be corrected for the fluid pressure gradient in the column to obtain a correct value for pressure at the transducer. If the transducer depth beneath the surface is less than about 1000 ft. and the calibrating fluid is a liquid, then a constant liquid density may be assumed with less than one percent error. The pressure correction is then given by ρgh, where ρ is the fluid density, g the acceleration of gravity and h is the height of the fluid column. In terms of specific gravity (relative to water) Sp.Gr., the pressure correction (in psi) is 0.434 x Sp.Gr. x h.

For greater accuracy or for greater transducer depths, the compressibility of the fluid must be considered. Figure 1 is taken from API STD 1101 (Manual of Petroleum Measurement Standards, Chapter 5, Section 2) and presents the compressibility of hydrocarbons as percent change in volume or density per 1000 psi pressure change for a range of API gravities and temperatures. Dividing the compressibility percentage obtained from figure 1 by 100,000 results in a factor F such that

$$\frac{d\rho}{\rho} = FdP$$

where $d\rho$ is the change in density associated with a change in pressure dP in psi.



Data reported in following: E. W. Jacobson, F. E. Ambrosius, J. W. Dashiell, and C. L. Crawford, "Compressibility of Liquid Hydrocarbons," *Proc. API* 25 (IV) 39-41 (1945).

~~FIG. 88~~ Mean Compressibility of Liquid Hydrocarbons ~~Based on Data from Zero to 1000 psig.~~

Fig 1.

Taken from API STD 1101

Integrating both sides results in

$$\ln \rho/\rho_s = F(P-P_s)$$

$$\text{or} \quad \rho = \rho_s e^{F(P-P_s)} \qquad (1)$$

where the subscript "s" indicates surface conditions. Equation (1) relates the density at any depth in the fluid column to the pressure at that point.

For a small change in fluid depth,

$$dP = \rho g dh \qquad (2)$$

where dh is the change in depth.
Substituting equation (1) into (2),

$$dP = \rho_s g e^{F(P-P_s)} dh$$

$$\text{or} \quad \rho_s g dh = e^{-F(P-P_s)} dP$$

Integrating from the surface to a total depth D,

$$\rho_s g D = -\frac{1}{F} e^{-F(P-P_s)} \Big]_s^D = -\frac{1}{F} e^{-F(P_D-P_s)} + \frac{1}{F}$$

Rearranging we have

$$e^{-F(P_D-P_s)} = 1-Fg\rho_s D$$

or $$P_D-P_s = \frac{-1}{F} \ln(1-Fg\rho_s D)$$

It is interesting to note that $g\rho_s D$ is the pressure head expected for an incompressible fluid. If $Fg\rho_s D \ll 1$ (that is, the fluid is nearly incompressible), then equation 3 simplifies to

$$P_D-P_s = g\rho_s D.$$

(note: $\ln(1+x) \approx x$ for $x \ll 1$.)

For an example of the type of error that might occur if compressibility is not considered, assume $g\rho_s D$ = 4000 psi (as it would for an approximately 10,000 ft. deep subsea completion), and that $F = 2 \times 10^{-5}\ psi^{-1}$. Thus,

$$P_D-P_s = -5 \times 10^4 \ln(1-0.08) = 4170 \text{ psi}.$$

If compressibility had been ignored, the pressure error would have been 170 psi. This analysis has assumed that temperature is constant with depth and that the compressibility of hydrocarbon liquids does not depend on pressure. The API STD 1101 values for compressibility were based on data from zero to 1,000 psig, so more data may be required to assure pressure independence.

For cases in which the subsea conditions have been specified (for example, setting a downhole pressure for calibration of a transducer), the surface pressure P_s, required to establish the condition is unknown. Thus the surface density required to solve equation 3 is also unknown. A derivation similar to the above shows that the hydrostatic pressure difference in terms of subsea conditions is

$$P_D - P_s = \frac{1}{F} \ln (1 + F\rho_D gD) \tag{4}$$

The density of the oil is most usually known at atmospheric pressure, so the density at pressure P_D is found from the atmospheric density, ρ_o, from equation 1.

$$\rho_D = \rho_o e^{FP_D} \tag{5}$$

The use of the above equation assumes a constant temperature, so that density variations in the tubing are caused only by pressure. The density at atmospheric pressure and the desired temperature are found by using table 23, API STD 2540 (ASTM-IP Petroleum Measurement Tables) to correct the standard density measured at 60°F relative to water at 60°F (Sp. Gr. 60/60°F). Specific gravity may be found from API gravity by using Table 3 from API STD 2540 or from the equation

Sp. Gr. 60/60°F = 141.5/(API Gravity at 60°F + 131.5).

In the following paragraphs several examples will be worked to demonstrate the use of the equations and to show the effect of a temperature gradient in the oil from the ocean floor to the surface. The example will include two different oils (20° and 60° API 60/60°F) at two temperatures (70°F and 120°F) and two completion depths (1,000 ft. and 10,000 ft.). The equations will be solved for surface pressure assuming a sea bottom transducer is being calibrated at 1,000 psi for the 1,000 ft. deep completion and at 5,000 psi for the 10,000 ft deep completion. The 1,000 ft. depth was chosen because it represents present capabilities for subsea completion; 10,000 ft. was chosen as a maximum depth for completions in the foreseeable future (in areas such as the Aleutian Basin).

Example 1

1,000 ft. completion -- P_D = 1,000 psi

20° API 60/60°F -- Sp. Gr. = 0.9340

Temp	From Fig. 1	From Table 23 (API STD 2540)
70°F	$F = 0.39 \times 10^{-5}\ psi^{-1}$	Sp. Gr. = 0.9305
120°F	$F = 0.50 \times 10^{-5}\ psi^{-1}$	Sp. Gr. = 0.9130

At 1,000 psi, $g\rho_{1000} = g\rho_o e^{F \times 1000} = 0.434 \times (Sp.\ Gr.)_o e^{F \times 1000}$

At 70°F: $g\rho_{1000} = 0.434\ (0.9305)\ e^{0.39 \times 10^{-5} \times 1000}$

$$= 0.405\ \frac{psi}{ft}$$

At 120°F: $g\rho_{1000} = 0.434\ (0.9130)\ e^{0.50 \times 10^{-5} \times 1000}$

$$= 0.398\ \frac{psi}{ft}$$

$$P_D - P_S = \frac{1}{F} \ln (1 + F\rho_D gD)$$

At 70°F: $P_D - P_S = \dfrac{1}{0.39 \times 10^{-5}} \ln (1 + 0.39 \times 10^{-5} \times 0.405 \times 1000)$

$= 405$ psi

$P_S = 1000 - 405 = 595$ psi

At 120°F: $P_D - P_S = \dfrac{1}{0.50 \times 10^{-5}} \ln (1 + 0.50 \times 10^{-5} \times 0.398 \times 1000)$

$= 398$ psi

$P_S = 1000 - 398 = 602$ psi

Thus if the surface pressure P_S were set at 599 psi, the pressure at the sea bottom transducer would be 1000 $\pm$ 4 psi even if the temperature of the 20° API gravity oil varied between 70° and 120°F.

Example 2

1,000 ft. completion -- P_D = 1,000 psi

60° API 60/60°F -- Sp. Gr. = 0.7389

Temp	From Fig. 1	From Table 23 (API STD 2540)
70°F	$F = 0.80 \times 10^{-5}\ psi^{-1}$	Sp. Gr. = 0.7344
120°F	$F = 1.10 \times 10^{-5}\ psi^{-1}$	Sp. Gr. = 0.7117

At 1000 psi, $\rho g_{1000} = g\rho_o e^{F \times 1000} = 0.434 \times (Sp.\ Gr.)_o e^{F \times 1000}$

At 70°F: $g\rho_{1000} = 0.434\ (0.7344)\ e^{0.80 \times 10^{-5} \times 1000}$

$= 0.321$ psi/ft

At 120°F: $g\rho_{1000} = 0.434\ (0.7117) e^{1.10 \times 10^{-5} \times 1000}$

$= 0.312$ psi/ft

$$P_D - P_S = \frac{1}{F} \ln (1 + F\rho_D g D)$$

At 70°F: $P_D - P_S = \dfrac{1}{0.80 \times 10^{-5}} \ln (1 + 0.80 \times 10^{-5} \times 0.321 \times 1000)$

$= 321$ psi

$P_S = 679$ psi

At 120°F: $P_D - P_S = \dfrac{1}{1.10 \times 10^{-5}} \ln (1 + 1.10 \times 10^{-5} \times 0.312 \times 1000)$

$= 311$ psi

$P_S = 689$ psi

Thus if the surface pressure P_S were set at 684 psi, the pressure at the sea bottom transducer would be 1000 $\pm$ 5 psi even if the temperature of the 60° API gravity oil varied between 70° and 120°F.

From the foregoing examples, it is apparent that for subsea completions up to 1000 ft, there is little effect on the calculated pressure at a subsea transducer due to compressibility and temperature. The pressure can be accurately calculated from

$$P_D - P_S = 0.434 \times \text{Sp. Gr.} \times D,$$

where the specific gravity of the oil at standard conditions has been corrected to the observed temperature (using an average between the subsea and surface oil temperatures) and line pressure.

Example 3

10,000 ft. completion -- $P_D = 5000$ psi

20° API 60/60°F Sp. Gr. = 0.9340

Temp	From Fig. 1	From Table 23 (API STD 2540)
70°	$F = 0.39 \times 10^{-5} psi^{-1}$	Sp. Gr. = 0.9305
120°	$F = 0.50 \times 10^{-5} psi^{-1}$	Sp. Gr. = 0.9130

At 5000 psi, $g\rho_{5000} = g\rho_o e^{F \times 5000} = 0.434 \times (\text{Sp.Gr.})_o e^{F \times 5000}$

At 70°F: $g\rho_{5000} = 0.434\ (0.9305)e^{0.39 \times 10^{-5} \times 5000}$

$= 0.412$ psi/ft.

At 120°F: $g\rho_{5000} = 0.434\ (0.9130)e^{0.50 \times 10^{-5} \times 5000}$

$= 0.406$ psi/ft

$$P_D - P_S = \frac{1}{F} \ln\ (1 + F\rho_D gD)$$

At 70°F: $P_D - P_S = \dfrac{1}{0.39 \times 10^{-5}} \ln\ (1 + 0.39 \times 10^{-5} \times 0.412 \times 10{,}000)$

$= 4087$ psi

$P_S = 5000 - 4087 = 913$ psi

At 120°F: $P_D - P_S = \dfrac{1}{0.50 \times 10^{-5}} \ln\ (1 + 0.50 \times 10^{-5} \times 0.406 \times 10{,}000)$

$$P_D - P_S = 4019 \text{ psi}$$
$$P_S = 981 \text{ psi}$$

Thus if the surface pressure P_S were set at 947, the pressure at the sea bottom transducer would be 5000 ± 34 psi even if the temperature of the 20°API gravity oil varied between 70° and 120°F.

Example 4

10,000 ft. completion $P_D = 5000$ psi

60° API 60/60°F Sp. Gr. = 0.7389

Temp.	From Fig. 1	From Table 23 (API STD 2540)
70°F	$F = 0.80 \times 10^{-5} \text{psi}^{-1}$	Sp. Gr. = 0.7344
120°F	$F = 1.10 \times 10^{-5} \text{psi}^{-1}$	Sp. Gr. = 0.7117

At 5000 psi, $g\rho_{5000} = g\rho_o e^{F \times 5000} = 0.434 \times (\text{Sp. Gr.})_o e^{F \times 5000}$

At 70°F: $g\rho_{5000} = 0.434\ (0.7344) e^{0.80 \times 10^{-5} \times 5000}$
$= 0.332$ psi/ft.

At 120°F: $g\rho_{5000} = 0.434\ (0.7117) e^{1.1 \times 10^{-5} \times 5000}$
$= 0.326$ psi/ft.

$$P_D - P_S = \frac{1}{F} \ln (1 + F\rho_D gD)$$

At 70°F: $P_D - P_S = \dfrac{1}{0.80 \times 10^{-5}} \ln (1 + 0.80 \times 10^{-5} \times 0.332 \times 10{,}000)$
$= 3277$ psi
$P_S = 5000 - 3277 = 1723$ psi

At 120°F: $P_D - P_S = \dfrac{1}{1.10 \times 10^{-5}} \ln (1 + 1.1 \times 10^{-5} \times 0.326 \times 10{,}000)$
$= 3203$ psi
$P_S = 5000 - 3202 = 1797$ psi

Thus, if the surface pressure P_S were set at 1760 psi, the pressure at the sea bottom transducer would be 5000 $\pm$ 37 psi even if the temperature of the 60° API gravity oil varied between 70° and 120°F.

From these example calculations for a 10,000 ft. completion, it is apparent that temperature variations cause relatively small errors in sea floor calibration pressures even for such a great depth. If the pressures are needed more accurately than this, then the temperature profile in the tubing would be needed.

It has thus been shown that relatively simple calculations of liquid hydrostatic head result in accurate pressure values for calibration of subsea transducers.

The calibration of gas pressure transducers is somewhat different. For low pressures and shallow depth, little correction need be made to the pressure measured at the surface. For a gas specific gravity, S.G. (relative to air at 20°C and 14.7 psia), pressure P(psia), and depth D(ft), the pressure correction ΔP is given by,

$$\Delta P = 3.56 \times 10^{-5} \times S.G. \times P \times D$$

This equation assumes that the ideal gas law holds and that $\Delta P/P$ is small. The equation may be modified to include the super-compressibility factor z as follows

$$\Delta P = 3.56 \times 10^{-5} \times S.G. \times D \times P/z.$$

For a 1000 ft. deep subsea completion, line pressure of 1000 psia (assuming S.G. = 1 and z = 1), ΔF = 36 psi. It is thus apparent that even with large errors in specific gravity and z, the pressure correction for hydrostatic head of the gas is small for depths up to 1000 ft.

Again for a line pressure of 1,000 psi, but a 10,000 ft deep completion, ΔP = 360 psi, so the assumption of $\Delta P/P$ being small no longer holds. An integration would thus be needed to determine the transducer pressure, and the variable z factor should be included in this integral. Thus, a closed form solution similar to that found for liquids cannot be obtained, and numerical integration is necessary. However, for a wide range of conditions, the equations presented for both liquids and gases allow accurate calibration of sea bottom pressure transducers through the production tubing.

applicable

6. Inspection Requirements and Test Procedures

The OCS Orders were reviewed for those items pertinent to a subsea system. The OCS inspection requirements and the suggested general inspection procedures for these items are discussed in the following paragraphs.

Tubing Plug

Inspection Requirements (OCS Order No. 5):

1. The sustained liquid leakage flow should not exceed 400 cc/min.

2. The gas leakage flow should not exceed 15 cu. ft/min.

General Procedure:

The first step in this procedure is to isolate a column of fluid between the tubing plug and the inspector with the valves opened as for production except that the tubing plug is in place. Any flow reaching the inspector at the surface is a direct indication of leakage past the tubing plug. Thermal equilibrium may be required if the maximum allowable leakage is too small. The flow volume can be measured at the surface in the same manner as for conventional platform systems.

Shut-in Tubing Pressure

Inspection Requirements (OCS Order No. 5):

1. Wells with a shut-in tubing pressure of 4000 psig or greater shall be equipped with a subsurface-controlled subsurface safety device.

What [illegible] order that requires [illegible]

[illegible]

2. When the shut-in tubing pressure declines below 4000 psig, a remotely controlled subsurface safety device shall be installed when the tubing is first removed and reinstalled.

General Procedure:

To determine if the shut-in tubing pressure is greater than 4000 psig, a pressure sensor should be located where the shut-in pressure can be sensed. A convenient arrangement is to locate a pressure sensor between the master valve and wing valve on each tubing. With the downhole safety valve and master valve opened and the wing valve closed, the shut-in tubing pressure as indicated by the sensor is noted.

Calibration of the pressure sensor can be accomplished by applying a known pressure at the surface to a closed column of fluid connecting the surface with the sensor with corrections calculated as explained in Section 5.

<u>Subsurface Safety Device</u>

Inspection Requirements (OCS Order No. 5):

1. A surface-controlled subsurface safety device shall be test operated every six months.

2. A subsurface-controlled subsurface safety device shall be removed, inspected and repaired every 12 months.

General Procedure:

To test a surface-controlled subsurface safety device, the well should be opened for production and the command then given to close the subsurface safety device. The leakage flow volume, if any, is measured at the surface in the same manner as for conventional platform systems.

Pressure Relief Valves

Inspection Requirements (OCS Order No. 8):

All pressure reli-f valves shall be either bench tested for operation or tested with an external pressure source (if the valve is so equipped) annually. Not for subsea

General Procedure:

To test a pressure relief valve for operation, the vessel or line should be pressurized to the pressure necessary to open the valve, by using the method suggested in Section 5. Unless remote position indicators are provided, a means to determine whether or not the valve has actually opened would have to be devised for each subsea system by observing the effect on the pressure sensors.

Pressure Sensors

Inspection Requirements (OCS Order No. 8):

All pressure sensors shall be tested at least once each month.

General Procedure:

To remotely test and calibrate a subsea pressure sensor it is necessary to:

(1) isolate a closed column of fluid from the surface to the subsea sensor by properly arranging the system's valves

(2) determine the specific gravity, compressibility and the column height of the fluid,

(3) select the pressure required at the subsea sensor,

(4) apply the appropriate pressure at the surface end of the column, and

(5) compare the telemetered pressure signal or indication with the pressure applied to the sensor.

Automatic Wellhead Safety Devices

Inspection Requirements (OCS Order No. 8):

All automatic wellhead safety devices shall be tested for operation and holding pressure once each month.

General Procedure:

To test the operation of the automatic wellhead safety devices, the out-of-the-tolerance condition (usually high or low pressure) which actuates the devices should be simulated. Unless position indicators are provided, a means to determine whether or not the valves have actually closed must be devised for each individual system because of the peculiarities in each system.

Check Valves should not be used in subsea systems

Inspection Requirements (OCS Order No. 8):

All check valves on all flow lines shall be tested for operation and holding pressure once each month.

General Procedures:

To test the check valve, it will have to be back pressured. The check valve fails to operate properly if any back flow through the valve occurs.

Liquid Level Shut-in Controls

Inspection Requirements (OCS Order No. 8):

All liquid-level shut-in controls shall be tested once each month by raising or lowering liquid level across the level-control detector.

General Procedure:

The preferable way to test the liquid-level shut-in controls is to simulate the out-of-tolerance conditions (liquid level either low or high) at the sensor. This simulation should cause either the inlet shutoff valve to close or the discharge shutoff valve to close. In this manner, both the control system and the automatic valves are tested. A means will have to be devised for each subsea system to determine if the out-of-tolerance condition actually occurred at the sensor if it was properly detected and if it caused the proper actuation.

Vessel Automatic-Inlet-Shutoff Valves

Inspection Requirement (OCS Order No. 8):

Inlet

All automatic-~~discharge~~-shutoff valves actuated by vessel ~~low-level~~ sensor~~s~~ shall be tested for operation once each month.

General Procedure:

Described above under general procedure for Liquid-Level Shut-In Controls.

Vessel Automatic-Discharge-Shutoff Valves

Inspection Requirement (OCS Order No. 8):

All automatic-discharge-shutoff valves actuated by vessel low-level sensors shall be tested for operation once each month.

General Procedure:

Described above under Liquid-Level Shut-in Controls.

High-temperature Compressor-Shutdown Controls

Inspection Requirement (OCS Order No. 8):

High temperature controls which protect the compressor against abnormal pressures solely by such temperature safety devices shall be tested annually.

General Procedure:

Because of the danger involved in elevating the temperature sufficiently to cause a temperature device to actuate, it is recommended that each temperature device be pre-tested and replaced each year rather than be tested remotely.

Oil Spill Detection Equipment

Inspection Requirements (OCS Order 7):

All platforms and structures are required to have curbs, gutters and spill pans connected to a tank or sump. This equipment is required to collect all hydrocarbon spillage on the platform. It is recommended that this requirement be extended to require all unenclosed subsea equipment to be covered by inverted spill pans with hydrocarbon sensors and sumps to remove spillage.

General Procedure:

To test the hydrocarbon spillage detection and removal system, a controlled spill should be made in each area or section of spill pans while the sump pumps are monitored for proper operation. This method will require a signal to the surface to indicate directly when the pumps are running or indirectly by indicating a pressure rise in the affected pipeline due to the pumping action. The indirect method is preferable because the pressure rise not only indicates the pumps are running but indicates they also are pumping fluid. One additional safeguard should be employed. A TV camera should be used to observe the spill pans in the vicinity of the spill to assure that they are not leaking due to damage or inadequacy of design.

Hydrocarbon Sensors

Inspection Requirements:

Hydrocarbon sensors are not covered in the OCS Orders presently in effect.

General Procedure:

The general test procedure for the oil-spill-detection equipment above will test the hydrocarbon sensors for operation. In addition, some means of knowing when each separate hydrocarbon sensor in the spill pan assemblies has sensed hydrocarbon will provide additional protection by warning of system degradation before the system is completely inoperable.

7. Summary and Recommendations

This report deals with the inspection problems that have arisen as a result of the present trend of the offshore oil industry towards subsea completion and production of deep water petroleum reservoirs. Inspection techniques for completion and production equipment are investigated, but inspection of riser systems, submersibles and structures are not included in the scope of this work.

A technique has been detailed for calibration of subsea sensors and for verifying the proper operation of valves. The technique requires only that the inspector have access to production tubing at the surface. By actuating subsurface control valves from the surface, the inspector can isolate a closed fluid path to the point of interest. Pressures read at the surface (when corrected for hydraulic gradients) may then be used to calibrate subsurface transducers. Flow rates measured at the surface can be used to indicate leakage rates from subsurface valves, but fluid in the tubing must be allowed to reach sufficient thermal equilibrium with its surroundings so that a false leakage rate is not indicated due to thermal expansion of the fluid.

This technique has been used to work out an inspection procedure for the Exxon Subsea Production System. The procedure demonstrates that the necessary closed fluid paths can be obtained to permit inspection of all necessary points. Thus from a theoretical point of view, it has been established that accurate evaluation of subsea conditions can be made from the surface. (To implement the procedures it would first be necessary to conduct an experimental program with field tests to determine operational problems.) delete

Agree